REGULATORY FLEXIBILITY COMMITTEE

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Authority: IC 8-1-2.5-9

MEETING MINUTES[1]

Meeting Date:	**September 22, 2009**
Meeting Time:	**10:00 A.M.**
Meeting Place:	**State House, 200 W. Washington St., Senate Chamber**
Meeting City:	**Indianapolis, Indiana**
Meeting Number:	**2**

Members Present: **Sen. James Merritt, Co-Chairperson; Sen. Edward Charbonneau; Sen. Beverly Gard; Sen. Jean Leising; Sen. Scott Schneider; Sen. Jean Breaux; Sen. Robert Deig; Sen. Sue Errington; Sen. Lonnie Randolph; Rep. Win Moses, Co-Chairperson; Rep. Matt Pierce; Rep. Kreg Battles; Rep. Ryan Dvorak; Rep. Sandra Blanton; Rep. Scott Reske; Rep. Dan Stevenson; Rep. Jack Lutz; Rep. Robert Behning; Rep. David Frizzell; Rep. Eric Koch; Rep. Ed Soliday.**

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[1] Exhibits and other materials referenced in these minutes can be obtained electionically by requesting copies at licrequests@iga.in.gov. Hard copies can be obtained in the Legislative Information Center in Room 230 of the State House in Indianapolis, Indiana. Requests for hard copies may be mailed to the Legislative Information Center, Legislative Services Agency,West Washington Street, Indianapolis, IN 46204-2789. A fee of $0.15 per page and mailing costs will be charged for hard copies. These minutes are also available on the Internet at the General Assembly homepage. The URL address of the General Assembly homepage is http://www.in.gov/legislative/. No fee is charged for viewing, downloading, or printing minutes from the Internet.

Members Absent: Sen. Dennis Kruse; Sen. Marlin Stutzman; Sen. Carlin Yoder.

Representative Win Moses and Senator James Merritt, Co-Chairmen of the Regulatory Flexibility Committee, convened the meeting at 10:10 a.m. Representative Moses announced that the meeting would include a morning session devoted to the topic of carbon capture and sequestration, followed by an afternoon session focusing on nuclear power.

(1) Carbon Capture and Sequestration:

Nancy LaPlaca:

Representative Moses invited testimony from Nancy LaPlaca, Energy Consultant with Bardwell Consulting in Denver, Colorado.[2] Ms. LaPlaca began by explaining that carbon capture and sequestration (CCS) involves capturing carbon dioxide (CO_2) produced in the combustion of fuel, and then storing that CO_2 in geological formations to prevent its release into the atmosphere. According to Ms. LaPlaca, CCS is being studied and proposed for use at integrated gasification combined cycle (IGCC) plants, which use a gasification process to turn coal into synthetic gas ("syngas"). This syngas can then be used to power gas turbines to produce electricity. However, most IGCC plants are used to produce chemicals, rather than electricity. Ms. LaPlaca reported that only two IGCC plants in the United States produce electricity.

Although CCS has been proposed for use in IGCC plants, no IGCC plants in the United States currently capture CO_2. According to Ms. LaPlaca, the high capital costs associated with both IGCC and CCS present a significant barrier to the implementation of these technologies. She testified that the capital costs associated with an IGCC plant translate to about 9¢-11¢/kWh, and that CCS would add 8¢-20¢/kWh to these costs. Ms. LaPlaca explained that there are several processes involved in CCS, including the capture, compression, transportation, re-pressurization, and sequestration of the CO_2 captured. Each one of these processes has its own costs associated with it. For example, the compression process alone costs approximately $17/ton of CO_2 compressed, due to the significant energy needed to compress the gas to 1/600th of its original volume and chill it to a temperature of -240° F. Ms. LaPlaca also noted that capturing CO_2 reduces plant efficiency by more than 20%.

Because of rising capital costs and limited performance guarantees, a number of IGCC projects have been cancelled in recent years. CCS projects have also been cancelled, including projects in Germany and Greenville, Ohio.

Ms. LaPlaca also discussed certain safety risks and liability issues associated with CCS, particularly with the long-term storage, or sequestration, of the captured CO_2. If the stored CO_2 leaks, the concentrated CO_2 can cause suffocation because it is heavier than air. An example of this phenomenon occurred in 1986 in Cameroon, when CO_2 was released from underneath a volcanic lake, suffocating 1,700 people. Sequestration can also lead to dangerous seismic events, such as those that occurred in Denver in the 1960s. In that case, toxic wastewater from the Rocky Mountain Arsenal was injected underground and later induced 1,500 seismic events over five years, including three earthquakes. Because of these risks to human safety, liability concerns may further impede the development of CCS projects. Ms. LaPlaca reported that proponents of CCS are seeking legislation to limit legal liabilities for CCS developers and utilities.

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[2] See Exhibit 1.

According to Ms. LaPlaca, there are only a few locations worldwide where CO_2 is captured and stored. The largest project is in Norway, where StatoilHydro has pumped 1,000,000 tons of CO_2 per year since 1996 beneath the North Sea. This and additional storage locations in Algeria and Weyburn, Canada, contribute to worldwide storage of approximately 3,000,000 tons per year. However, Ms. LaPlaca stressed that the amount of CO_2 currently being stored is insignificant compared to the 2,000,000,000 tons of CO_2 emitted each year by coal plants in the United States alone. Ms. LaPlaca cited estimates by the International Energy Agency that the world would need 6,000 CCS projects, each injecting 1,000,000 tons of CO_2 per year into the ground, to store the CO_2 emissions anticipated in the years ahead.

Ms. LaPlaca also testified that there are risks of leakage and "fugitive emissions" in all stages of the CCS process. For example, during the injection process, liquefied CO_2 is pumped under extreme pressure over a mile underground, sometimes into a water-bearing rock stratum, where it can form carbonic acid. This acid can, in turn, leach rock and metals. In addition, because the stored CO_2 is under great pressure, it tends to migrate along any suitable pathway in the rock. As a result, once the CO_2 is buried, its location cannot be precisely known. This tendency of the compressed CO_2 to migrate makes it difficult to know where to monitor for leakage.

Finally, Ms. LaPlaca noted that a coal-fired power plant with CCS would use twice as much water as a traditional coal-fired plant. Ms. LaPlace argued that the effects on local water supplies must be considered when siting new power plants or implementing CCS technology. She pointed out that more water is used to generate electricity and operate appliances than is used directly in kitchens and bathrooms and to water lawns.

After concluding her presentation, Ms. LaPlaca answered questions from Committee members. Representative Lutz asked what solutions Ms. LaPlaca would propose for meeting Indiana's future energy needs, in light of her testimony critical of IGCC plants and CCS. Ms. LaPlaca pointed to wind and solar power as potential sources of new energy for both Indiana and the nation. She noted that Germany, which does not have the wind or solar resources available in the United States, has four times as many solar photovoltaic (PV) installations as in the United States and nearly as much installed wind capacity.

Representative Battles noted that there are underground natural gas storage facilities in his legislative district in Knox County. He asked whether the risks of leakage were the same with stored natural gas as with stored CO_2. Ms. LaPlaca suggested that there would be different risks involved, given the different physical and chemical natures of the two substances. Representative Battles then asked whether any leaking associated CCS would mainly be due to a poor choice of the geological area selected for storage. Ms. LaPlaca agreed that would be true, noting that the need to somehow seal the stored CO_2 presents the largest obstacle to successfully implementing CCS.

Kerwin Olson:

Next, the Committee heard from Kerwin Olson, Program Director for the Citizens Action Coalition (CAC).[3] Mr. Olson began by comparing the costs of various technologies used for electricity generation. He cited 2009 statistics from the energy provider Dynegy indicating that the cost for a traditional coal-fired power plant without CCS is $3,000-

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[3]See Exhibit 2.

$4,200/kW, versus $3,800-$4,900 for an IGCC plant without CCS.[4] In 2008, statistics from the Federal Energy Regulatory Commission (FERC) indicated that the cost for a traditional coal-fired power plant without CCS was $2,300-$4,000/kW, versus $2,500-$5,500 for an IGCC plant without CCS. In contrast, Dynegy reported the cost of wind power to be $2,000-$2,200/kW in 2009, and FERC reported the cost of wind to be $1,800-$2,600/kW in 2008.

Given the lower costs for wind energy cited by both Dynegy and FERC, Mr. Olson argued that wind development should continue to be pursued in Indiana. He noted that the National Renewable Energy Laboratory (NREL) has estimated that Indiana has the potential for 40,000 MW of wind energy. In addition, Indiana had the fastest growth in wind power development among all states in 2008. Mr. Olson testified that by the end of 2010, Indiana will have over 1,000 MW of wind energy installed, at an average cost of $2,000/kW.

As did Ms. LaPlaca, Mr. Olson discussed the high capital costs and decreased energy output associated with CCS. He cited a 2009 Harvard study that concluded a new coal-fired plant with CCS would generate electricity at a cost of 18-22¢/kWh, not including transportation and storage costs. Mr. Olson compared this cost to Indiana's average residential electric rate of 9.64¢/kWh in June 2008. The Harvard study also found that capturing 90% of a plant's CO_2 emissions would result in a 25% increase in capital costs and a 27% decrease in net power output for the plant. According to the study, these figures together suggest an approximately 70% increase in capital costs per kW of net power output. As an example of the high costs associated with CCS, Mr. Olson pointed to Duke Energy Indiana's (DEI's) new IGCC plant in Edwardsport. He reported the current cost of the project to be $2.35 billion, not including CCS.

Turning to the potential for CCS at the Edwardsport plant, Mr. Olson noted that in testimony filed with the Indiana Utility Regulatory Commission (IURC) in October 2006, DEI suggested that significant sequestration potential might exist below the site area. According to Mr. Olson, DEI later changed its assessment in July 2009, when it filed testimony stating that geological data gathered by the company indicated that the sequestration potential of the site area was less than optimal.

Mr. Olson next focused on the geological challenges presented by the long-term underground storage of CO_2. Among the challenges he highlighted were the risks of seismic activity, including earthquakes. Mr. Olson noted that DEI's Edwardsport project in southwestern Indiana is located near the New Madrid Fault Line and within the Wabash Valley Seismic Zone.

In discussing additional challenges presented by CCS, Mr. Olson again pointed to testimony filed by DEI concerning its Edwardsport plant. He quoted DEI testimony acknowledging uncertainties surrounding the ownership of underground pore space and long-term stewardship requirements for CCS projects. He also read DEI testimony indicating that public acceptance could pose a major hurdle to the advancement of CCS technology. According to Mr. Olson, the cancellation of the Midwest Regional Carbon Sequestration Project in Greenville, Ohio, was largely the result of public opposition to the project.

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[4]According to Mr. Olson, the report from Dynegy indicated that CCS costs were not included in its energy cost statistics because CCS is not available in the United States.

Returning to the issue of cost, Mr. Olson noted that DEI had sought a tracker[5] to allow it to recover CCS costs through its rate base. Mr. Olson maintained that this tracker, dubbed the "Carbon Management Rider" in DEI's petition, actually concerns carbon storage, not carbon management. He further argued that the proposed tracker was another example of "single-issue ratemaking."

In addition to quoting filed testimony in DEI's proceedings before the IURC, Mr. Olson quoted remarks made in September 2009 by Jim Rogers, President and CEO of Duke Energy. In particular, he cited Mr. Roger's statements that it would be unlikely that the United States could develop and bring to scale CCS.

Mr. Olson concluded his remarks by asserting that CCS is unproven, expensive, and unnecessary, stating that alternatives exist that are proven, cheaper, and cleaner.

John Rupp:

After Mr. Olson's presentation, the Committee received testimony from John Rupp, Assistant Director for Research, and Section Head, Subsurface Geology at the Indiana Geological Survey.[6] Mr. Rupp explained that the geological potential for CCS in Indiana involves technical, regulatory, economic, and societal considerations. He indicated that he would focus on the technical factors relevant to Indiana's geology. He further noted that the technical feasibility of CCS in turn depends on a number of factors, including storage capacity and seal integrity, operational functionality, and monitoring, verification, and accounting.

Before a CCS project is implemented, developers must ensure that there is adequate storage capacity and seal integrity in the area of the project site. Mr. Rupp explained that there must be both surface and subsurface spatial availability to meet the needs of the CO_2-producing source. Once a project is online, operational functionality will require that storage reservoirs have adequate permeability, low chemical reactivity, and pressure tolerances that allow for the high-volume injection of CO_2. Assuring the operational functionality of a CCS project will also require engineering expertise, given the need to design and install pipelines and compression and injection systems at the project site. Finally, after a CCS project is operational, there will be a need for appropriate monitoring, verification, and accounting systems to ensure that injected CO_2 volumes are traceable, and that they remain in the reservoir, isolated from groundwater and other subsurface natural resources.

Next, Mr. Rupp reported on the current scientific understanding of the region's potential to accommodate CCS projects. He explained that the U.S. Department of Energy (DOE), along with other partners, has completed the first phase of a study to determine the geological capacity of the region to store CO_2. In this initial phase, a number of potential reservoirs and geological seals were identified, including saline aquifers, enhanced oil recovery (EOR) fields, and coal and shale beds. In the ongoing second phase of the investigation, small-volume injection tests have been completed in Michigan and West Virginia, and another such test is underway in Kentucky. In addition, a large-volume

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[5]A "tracker," or an adjustable rate mechanism, allows a utility to recover through its rates certain expenses without the utility having to bring a formal rate case. Through an expedited process, the IURC reviews the costs incurred by a utility and associated with the particular tracker.

[6]See Exhibits 3 and 4.

injection test has been initiated in Illinois.

Mr. Rupp noted that the focus of the scientific investigation to date has been on saline aquifers, particularly those beneath the Mount Simon Sandstone formation in the upper Mississippi Valley and southern Great Lakes areas, including Indiana. These studies have indicated that the porosity of the rock formation decreases the deeper below the surface the rock is located. This finding is important, because the greater the pore volume of the rock, the greater the rock's potential storage volume.

Mr. Rupp also reported on the investigation of EOR techniques in oil fields in the region. He explained that EOR increases the amount of oil that can be extracted from an oil field. The process involves injecting CO_2 into the oil-bearing stratum under high pressure, which helps push the oil to the surface. According to Mr. Rupp, several small-volume tests have been conducted in Illinois over the past 30 years. In addition, a "flood test" involving the injection of immiscible CO_2 is ongoing at Sugar Creek, Kentucky, and a miscible flood test is planned for a site in Indiana in Posey County.

Just as EOR can be used to increase oil recovery in oil fields, enhanced coal bed methane (ECBM) recovery can be used to produce additional coal bed methane from a bituminous coal bed. Mr. Rupp reported that a test of this process was conducted in Wabash County, Illinois, in 2008. The preliminary results indicated that the coal seams studied did not have a high gas content.

Returning to the issue of storage volume, Mr. Rupp testified that approximately 250 million metric tonnes (mmt) of CO_2 per year are produced in Indiana.[7] This means that if half of Indiana's annual CO_2 emissions are to be captured and stored, a reservoir capacity of 125 mmt per year will be required. To date, the largest CCS projects store about 1-1.5 mmt of CO_2 per year. In Indiana, potential storage capacity includes about 25-60 billion tonnes in Mount Simon Sandstone, less than one billion tonnes in mature oil fields and coal seams, and possibly 5 billion tonnes in organic shale formations. However, the DOE's National Energy Technology Laboratory (NETL) has calculated that only 1-4% of the available pore space present in the region is useable.

In ending his remarks, Mr. Rupp suggested that to better understand the region's potential for CCS, additional testing is needed, including larger volume tests in the Mount Simon Sandstone formation, EOR evaluations in Indiana oil fields, and the identification and testing of other reservoirs. In addition, transportation options, such as inter- and intra-regional pipelines, will have to be studied. At specific storage sites, actual reservoir and seal characteristics will have to be analyzed, and calibrated simulations of migration and monitoring performed. He concluded that the initial assessment of the geological potential for CCS in Indiana is encouraging. According to Mr. Rupp, the work ahead now involves converting "potential into proven" by conducting further tests and long-term monitoring.

Representative Moses then asked about the cost of moving from potential to proven technical capabilities for CCS. Mr. Rupp indicated that DEI has been granted approval from the IURC to conduct a $17 million study to assess the feasibility of incorporating CCS at its Edwardsport plant. An additional $121 million would be needed to prove CCS at the project site.

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[7]According to Mr. Rupp, of the 250 mmt of CO_2 produced annually in Indiana, about 160 mmt comes from point sources, mainly from coal-fired generation plants. For example, DEI's Gibson Station (3,100 MW) emits about 20 mmt of CO_2 per year, and DEI's Edwardsport IGCC plant (630 MW) is expected to emit about 4.5 mmt of CO_2 per year when it goes online in 2012.

Representative Pierce asked how long it would take to prove the potential CCS sites that have been identified. Mr. Rupp answered that the regional investigation conducted by the DOE-led partnership has occurred in phases. The first phase, which is largely completed, took two years and involved the initial assessment of reservoirs and seals. The second phase, which is ongoing, involves characterization of the identified reservoirs and seals and will take about four years to complete. The third phase, which will involve large-volume testing will take about ten years to complete.

Representative Moses asked about the results of an assessment of the Edwardsport site that the Indiana Geological Survey performed in 2006. Mr. Rupp replied that at the time of the assessment, the relationship between porosity and reservoir depth was not known. However, with the subsequent discovery of the inverse relationship between these two factors, it is now known that the porousness of the rock near the Edwardsport plant is poor.

Kay Pashos:

Next, Kay Pashos, an attorney with Baker & Daniels LLP, discussed the policy and legal issues associated with CCS.[8] Ms. Pashos began by encouraging policymakers to continue investing time and resources to explore the possible use of CCS technology in Indiana. She testified that such investments are justified, given Indiana's heavy reliance on coal to produce electricity. According to Ms. Pashos, coal-fired power plants account for 35-40% of all CO_2 emissions in the United States. Proposed federal climate change legislation would require an 80% or greater reduction in CO_2 emissions by 2050. Given the likeliness of federal CO_2 reduction requirements, Ms. Pashos maintained that the state should consider all potentially feasible means of addressing these requirements, including CCS.

Ms. Pashos next highlighted some of the key policy and legal issues presented by CCS, including project siting, property rights acquisition, project closure, and long-term storage issues. She noted that there is no federal, state, or regional regulatory framework in place to address these issues. She did point out, however, that the U.S. Environmental Protection Agency (EPA) has recently proposed rules to regulate CO_2 injections using its authority under the Safe Drinking Water Act. Ms. Pashos suggested that Congress or state legislatures will need to determine whether the entities that capture, transport, and store CO_2 will be regulated and, if so, whether the federal government or the states will be responsible for that regulation. Ms. Pashos posited that there are several agencies that could potentially regulate one or more aspects of the CCS process, including the EPA at the federal level, or the Indiana Department of Environmental Management (IDEM) or the Department of Natural Resources (DNR) at the state level.

Turning to the issue of property rights, Ms. Pashos noted the potential implementation of CCS raises the question of who will have control over the underground pore space in the storage formations. Ms. Pashos suggested that surface property owners, mineral rights owners, or the state could all potentially have an interest in the sites involved. Ms. Pashos wondered whether the entities that would propose to store the CO_2 would acquire the necessary property rights to use the underground pore space, along with any necessary surface property, through bilateral transactions with property owners or by asserting eminent domain rights. She also wondered what sort of compensation there would be for the use of underground pore space for CO_2 storage.

With respect to the issue of project closure, Ms. Pashos indicated that it is not clear who

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[8] See Exhibit 5.

will assume the long-term, post-closure liability associated with CO_2 storage sites. Project operators, the state, or federal government could all potentially be responsible. The issue of liability, and all other questions surrounding CCS, are further complicated by the fact that many potential underground storage formations will cross state lines. Ms. Pashos suggested that a number of frameworks could emerge to address these issues, including state-by-state legislation, multi-state compacts, or federal regulations.

After describing the key legal and policy issues surrounding CCS, Ms. Pashos argued that even if the outstanding questions are adequately addressed, the states and the federal government will still need to provide incentives to encourage CCS, such as tax credits, property tax abatements, and incentives for initial site characterization work.

Having emphasized the need for incentives, Ms. Pashos then highlighted a number of state and federal initiatives concerning CCS. She first displayed a map showing fourteen states that have enacted laws or regulations addressing CCS.[9] Ms. Pashos explained that those state measures do one or more of the following:[10]

- Create CCS study committees.
- Establish permitting frameworks for CCS.
- Provide incentives for CCS.
- Address long-term liability for CCS projects.
- Address pore space ownership.
- Provide for cost recovery for certain CCS costs.

Regionally, the Midwestern Governors Association has developed what Ms. Pashos termed a "legislative toolbox" in an effort to coordinate the CCS initiatives and other energy policies of its member states.

At the federal level, the American Recovery and Reinvestment Act (ARRA) has provided funding or grants for the following CCS and coal initiatives:

- Research into low-emissions coal plants.
- Industrial carbon capture and energy efficiency improvement projects.
- Identification of CO_2 storage sites.
- Training and research on safe storage of CO_2 emissions.

Ms. Pashos described additional proposals being considered by Congress and the Administration, including the following:

- Competitive grants for certain energy technologies, including CCS.
- Creation of a Clean Energy Deployment Administration to provide loans and loan guarantees to spur private investment in energy technology.
- $1 billion for CCS demonstration and deployment each year (to be funded by a charge on consumers of fossil fuel-based electricity).
- Various CO_2 capture requirements for coal-fired power plants permitted after certain dates.

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[9] See Exhibit 5.

[10] See Appendix 1 in Exhibit 5 for a table summarizing CCS legislation enacted in other states.

- Bonus emissions allowances for electric utilities that act early to adopt CCS.

Ms. Pashos also reported that a separate energy bill before Congress provides that the federal government would assume long-term liability for the first ten commercial CCS projects.

Ms. Pashos concluded her testimony by noting that the various proposals now before Congress fail to address several important issues surrounding CCS, including property rights and pore space usage, sequestration resource management, and incentives for sequestration site exploration.

After ending her remarks, Ms. Pashos shared a video presentation that showcased American Electric Power's (AEP's) CCS Validation Project at its Mountaineer Plant in New Haven, West Virginia.

Following the video presentation, Ms. Pashos fielded questions from Committee members. Representative Koch asked whether insurance companies were likely to offer products to cover liabilities associated with the closure of CCS projects, such as the policies currently available to landfill operators. Ms. Pashos responded that she thought such products would become available as CCS projects are implemented.

Representative Pierce asked whether it made sense for the legislature to enact CCS policies in the 2010 session when the science behind the technology is still evolving. Ms. Pashos suggested that those states that have CCS frameworks in place will attract CCS developers and investors over states that have not adopted such policies.

Senator Randolph commented to the Committee's Co-Chairmen that he would like any future discussions of CCS to address the environmental implications of CCS and the costs to consumers of implementing CCS.

At 1:10 p.m., the Committee recessed for lunch.

(2) Nuclear Power:

Mark Cooper:

At 2:15 p.m., Representative Moses reconvened the meeting and invited testimony from Mark Cooper, a fellow at the Institute for Energy and the Environment at Vermont Law School.[11] Dr. Cooper discussed the costs of constructing nuclear power plants, focusing on a cost recovery mechanism known as construction work in progress (CWIP). Dr. Cooper explained that CWIP allows a utility to recover, through its rate base, certain construction costs while the construction is ongoing. He noted that utilities seeking CWIP from state regulators maintain that by reducing the carrying charges for money spent before a reactor comes online, the utility's total revenue requirement is reduced. Dr. Cooper argued that this justification for CWIP rests on six faulty assumptions:

- The assumption that the reactor is the least-cost option. Dr. Cooper maintained that nuclear reactors are substantially more expensive than other alternatives. He argued that the relevant comparison is not between a reactor with CWIP and one without CWIP, but

[11] See Exhibit 6.

between a reactor with CWIP and the actual least-cost option.

- The assumption that there will be no cost overruns for a project. According to Dr. Cooper, the history of the nuclear industry in the United States and abroad includes many projects afflicted by cost overruns. He testified that CWIP may induce utilities to continue with projects despite cost escalations, because CWIP allows the costs to be passed along to ratepayers.

- The assumption that growth in demand for electricity will be stable and accurately predicted. Dr. Cooper noted that reactors take significant investments of time and capital to build. If demand growth slows or is overestimated, CWIP may encourage utilities to proceed with nuclear projects despite the resulting excess capacity. According to Dr. Cooper, the current economic recession has lowered near-term projections for demand and spurred changes in consumer behavior that are likely to result in lower load growth than expected.

- The assumption that projects for which CWIP has been granted will be completed. Dr. Cooper testified that in the first round of reactor construction in the 1970s and 1980s, about half of the plants were cancelled or abandoned. In what he termed the current "nuclear renaissance," nearly every reactor has been abandoned or delayed. When CWIP is allowed, the risks and costs of cancelled plants are shifted to ratepayers.

- The assumption that CWIP will not adversely affect a utility's financial rating. According to Dr. Cooper, if CWIP encourages a utility to undertake a risky project that it would not have otherwise attempted, and the utility suffers a credit rating downgrade as a result, the increase in the total cost of the electric service that is eventually delivered will offset any accounting savings resulting from CWIP.

- The assumption that ratepayers' money cannot be put to better use. Dr. Cooper asserted that ratepayers are better served by investments in efficiency measures, which allow consumers to have use of their money in the near term.

Dr. Cooper claimed that if any one of the assumptions used to justify CWIP is faulty, ratepayers end up worse off. He concluded by stating that CWIP should not be used to shift the risks of nuclear plant construction to ratepayers, given the uncertainties surrounding demand projections, project costs, technology, and public policy.

Representative Moses asked about nuclear power projects underway in France and China. Dr. Cooper indicated that the companies building the plants in those two countries are largely government-owned. He explained that it is much harder to get private investors to finance nuclear plants, due to the plants' capital-intensive nature and the ten or more years needed for construction. Dr. Cooper noted that a plant under construction in Finland is three years behind schedule and $3 billion over budget.

Senator Randolph asked whether there are any advantages to nuclear plants, notwithstanding the time and cost concerns associated with them. Dr. Cooper conceded that once nuclear plants are online, they are relatively inexpensive to operate. As a result, electricity rates are high during the initial years a plant is in operation, while capital costs are still being recovered. However, once the capital costs have been recovered, rates will decrease, reflecting the lower operational costs. According to Dr. Cooper, electricity from a nuclear plant can cost up to 18¢/kWh during the first year of operation, and can be as low as 4¢/kWh during the 41st year of operation.

Kerwin Olson:

Kerwin Olson of the CAC addressed the Committee again to provide testimony about nuclear power.[12] Mr. Olson began by describing two failed attempts to build nuclear power plants in Indiana:

- **Bailey Nuclear Plant:** This plant was proposed by NIPSCO in 1967 and received a permit from the U.S. Atomic Energy Commission[13] in 1974. In 1981, the project was cancelled. At the time of cancellation, $191 million had been spent on the project, and construction was 1% complete. In 1984, the Indiana Supreme Court ruled that NIPSCO could not amortize the cancelled project's costs over a 15-year period. NIPSCO was required to refund $81 million to ratepayers for rate increases associated with the project.

- **Marble Hill Nuclear Plant:** This plant was proposed by PSI Energy (now Cinergy) in 1973 and received a permit in 1977. In 1979, construction was halted on three separate occasions. Cost overruns from 1980-1984 caused a slowdown in construction, leading then-Governor Robert Orr to create a task force to study the plant. In 1984, the plant was cancelled after $2.8 billion had been spent, and the project was 20% complete. In 1986, PSI received a rate increase through a regulatory order. That order was appealed all the way to the U.S. Supreme Court, which in 1991 ordered PSI to refund $150 million to ratepayers.

Mr. Olson then discussed several incidents involving AEP's Donald C. Cook nuclear plant near Bridgman, Michigan:

- In the 1990s, safety backup systems at the plant did not function properly, causing a shutdown of the plant. A settlement agreement in 1999 required AEP to refund $55 million to ratepayers for the costs of replacement power. The agreement also included a five-year rate freeze. AEP was not allowed to recover $500 million in costs associated with repairs.

- Both generating units at the plant were shut down on April 24, 2003, when 2,000,000 fish entered intake pipes.

- On September 20, 2008, a fire shut down a turbine building, which

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[12]See Exhibit 7.

[13]The U.S. Atomic Energy Commission was eventually replaced by the U.S. Nuclear Regulatory Commission (NRC), which began operations on January 19, 1975. U.S. NRC, Our History, http://www.nrc.gov/about-nrc/history.html (last visited October 26, 2009).

still remains closed. Repairs are expected to cost $332 million.

- The NRC has taken enforcement actions against the plant five times since 2004.

Turning to the status of nuclear power in other countries, Mr. Olson focused on the industry in France, stating the following:

- Only 1% of France's spent nuclear fuel is reprocessed; the rest remains as highly radioactive waste.

- The decommissioning of France's first reprocessing facility will cost $6 billion and take until 2040.

- Nuclear power plants dump 100 million gallons of waste into the English Channel annually.

- In July 2008, 8,000 gallons of radioactive waste spilled into two rivers, threatening human populations.

- Even with nuclear power, only 8.5% of France's total energy is produced in France. In July 2009, one-third of France's reactors were shut down due to heat waves, forcing the country to import electricity from Great Britain.

Mr. Olson also described accidents at the Three Mile Island Nuclear Generating Station in 1979 and at the Chernobyl Nuclear Power Plant in 1986. Focusing largely on the costs associated with Three Mile Island, Mr. Olson reported that construction of the plant, which came online in December 1978, cost $425 million. Clean-up costs after the accident totaled $975 million. Nearly $100 million in documented damage claims have been paid out since the accident. With respect to the Chernobyl accident, Mr. Olson discussed the effects on human health. He noted that a 17-mile "exclusion zone" remains in effect around the Chernobyl plant site, having displaced 336,000 people. While official reports attribute 56 deaths to the accident, scientists and government officials in Belarus and Ukraine have reported tens of thousands of cancer deaths, genetic abnormalities, and epidemics since the accident.

Focusing next on the radioactive substances associated with nuclear power, Mr. Olson discussed Strontium 90, Plutonium 239, and other radioactive emissions. He testified that nuclear power presents "unsolvable waste issues," in that nuclear emissions can remain radioactive for 250,000 years. According to Mr. Olson, discharged fuel rods are 1,000,000 times more radioactive than when they enter a plant as fresh fuel. The high radioactivity of spent fuel rods makes any instances of leakage extremely dangerous. Mr. Olson noted that leakage does occur, pointing to recent leaking in 67 of the 177 underground tanks of radioactive waste stored at the DOE's Hanford Site in the state of Washington.

Despite the dangers posed by radioactive waste, Mr. Olson argued that the reprocessing of spent nuclear fuel should not be pursued. He explained that the practice ended in the United States in 1977, due to concerns about nuclear weapons proliferation. Arguing that the United States should not enter into any international reprocessing agreements, Mr. Olson claimed that it would cost the nation $2-$3.5 billion annually to reprocess just its existing waste. A reprocessing facility would cost $20 billion, and the United States would need two such facilities to handle its current levels of waste. Mr. Olson maintained that reprocessing would increase the nation's vulnerability to terrorism and could restart the

Cold War.

With respect to the use of nuclear power as a way to meet any requirements imposed by potential climate change legislation, Mr. Olson displayed a list of the number of grams of CO_2 emitted per kilowatt hour of electricity generated from various sources.[14] He pointed out that while the 66 g/kWh of CO_2 emitted by a nuclear power plant is considerably less than the 960-1050 g/kWh of CO_2 produced by a coal-fired plant, it is not as low as the 8-18 g/kWh from a solar PV installation, or the 10 g/kWh from onshore wind power. However, the amount of CO_2 emitted from nuclear power is only one factor to consider, because the chlorofluorocarbons (CFCs) emitted during the enrichment process are 10,000 times more potent in trapping greenhouse gases than is CO_2. Even if nuclear power plants were an environmentally sound alternative to fossil fuel-powered plants, Mr. Olson suggested that nuclear power cannot be deployed quickly or cost effectively enough to meet potential carbon reduction mandates. He testified that one new reactor per week would have to come online in order to achieve a 20% reduction in global CO_2 emissions.

Finally, Mr. Olson testified about the subsidies that the nuclear power industry has received in the United States. He reported that the federal government invested $70 billion in research and development for nuclear power from 1948-1998. Furthermore, the Price-Anderson Act partially indemnifies the non-military nuclear industry against liability claims arising from nuclear incidents. Mr. Olson concluded by stating that public policy should no longer focus on subsidizing the coal and nuclear industries, but should focus instead on strengthening the renewable energy sector.

Senator Gard asked whether the renewable energy sector can be developed without government subsidies to the degree needed to address global climate change. Mr. Olson replied that developing renewable energy will require subsidies, but only a portion of those that have been given to the traditional energy sector.

Senator Merritt announced that he had recently toured AEP's Cook plant in Michigan and offered to talk to fellow Committee members about his experience there.

Finally, Senator Randolph asked whether nuclear power provides any benefit to consumers. Mr. Olson answered that it does not.

<u>Leslie Kass</u>:

Leslie Kass, Director of Business Policy and Programs for the Nuclear Energy Institute, argued that Indiana and other states should strive to achieve a diversified energy portfolio that includes nuclear power among other energy sources.[15] Ms. Kass reported that nuclear energy accounts for 19.6% of the total electricity generated in the United States, with 104 plants currently operating. However, in 2008, nuclear power accounted for 72.3% of the nation's electricity sources that do not emit greenhouse gases during operation.

Ms. Kass next displayed a map showing 23 potential locations for nuclear plants in the United States.[16] She indicated that 16 applications for plants are under review at the

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[14]See Exhibit 7.

[15]See Exhibits 8 and 9.

[16]See Exhibit 8.

NRC. Ms. Kass then described improvements in the construction and licensing process over the past 30 years. For example, utilities formerly had to secure two permits—one for construction and one for operating the plant. Today, utilities apply for a combined construction and operating license (COL). In addition, plant design used to proceed as a plant was being built. Now, most design work is completed before construction begins. During the first wave of plant construction in this country, there was no design standardization. Now, the industry uses standard, NRC-certified designs and incorporates more efficient construction management practices, such as the use of modular construction. Even the opportunities for public input have improved, with citizens now able to intervene at well-defined points in the licensing and construction process, rather than when a plant is essentially complete.

Ms. Kass argued that despite the longer period needed for construction, new nuclear plants will be competitive with other forms of generation. She reported that state public service commissions in Florida, Georgia, and South Carolina have recently approved new nuclear plants. Ms. Kass acknowledged that the construction of new nuclear plants does involve financing challenges, because the projects themselves are very large compared to the size of the companies building them.[17] However, she maintained that these challenges can be managed through supportive rate policies at the state level and loan guarantees from the federal government.

Having concluded her presentation, Ms. Kass accepted questions from the Committee. Representative Moses asked about the average price per kilowatt hour for electricity generated by a nuclear plant. Ms. Kass answered that the cost is about 8.6¢/kWh for electricity from a new plant, versus 1.87¢/kWh for electricity from an old plant.

Representative Koch asked whether CWIP offers any reward for consumers in exchange for their bearing the risks associated with the construction of a nuclear plant. Ms. Kass responded that CWIP allows ratepayers to avoid the "rate shock" that would occur if construction costs were not reflected in rates until construction is complete. She explained that CWIP prevents ratepayers from having to pay "interest on interest," because the financing costs incurred by the developer are paid off as construction progresses, preventing carrying costs from accumulating and being capitalized over the life of the loan.

When asked further about the implications of CWIP for consumers by Senator Randolph, Ms. Kass explained that CWIP provides for the real-time evaluation of project costs by regulators, as well as the real-time recovery of those costs by utilities. For example, in South Carolina, expenses eligible for CWIP are required to be submitted to regulators for review on a quarterly basis. Ms. Kass emphasized that CWIP only allows a utility to recover interest expenses, and not principal payments, during construction.

Senator Errington asked when CWIP recovery begins. Ms. Kass indicated that it begins before actual construction, during the licensing and site-preparation phase of a project.

Referencing Mr. Olson's testimony, Representative Frizzell inquired about the adequacy of the high-grade uranium supply to fuel nuclear plants and about potential security threats posed by nuclear power. Ms. Kass testified that both concerns have been addressed by the Megatonnes to Megawatts Program, in which the United States and Russia have

[17]Ms. Kass explained that while a new nuclear plant might have a $6 billion capital requirement, the company building it might have a market capitalization of $35 billion. In that case, the plant would represent over one-sixth of the company's total market value.

partnered to convert weapons-grade uranium into fuel for nuclear power plants. She also reported that the nuclear industry has invested $1.2 billion in security measures since the terrorist attacks on September 11, 2001, and has conducted emergency response drills with the FBI and state and local agencies.

Senator Breaux asked why the industry seeks to have ratepayers finance the costs of construction through CWIP, rather than seeking funds from private investors. Ms. Kass responded that a minimum investment of 20% equity is required for construction. Utilities seek CWIP because it improves their cash flow by including interest costs in the rate base as they are incurred. The improved cash flow in turn supports stronger financial ratings, which result in lower overall interest costs for a project. Ms. Kass noted that even with CWIP, most of the money for a project will come from the utility itself and private investors. Senator Breaux then asked how much of the construction is financed through CWIP. Ms. Kass indicated that ratepayers contribute about 10% of the project costs.

Noting that 94% of Indiana's electricity is currently generated from coal, Senator Leising asked Ms. Kass her opinion about the appropriate mix of generating resources in an ideal energy portfolio for the state. While declining to identify specific percentages for different resource types, Ms. Kass encouraged policymakers to pursue a diverse portfolio for Indiana. She further suggested that the state should carefully consider at what points in the future its demands for energy are likely to grow.

Representative Moses noted that the ongoing construction of a power plant in France is largely being financed by the French government. He asked about the likelihood of cost increases for the project. Ms. Kass stated that it is too early to tell at this stage of construction. However, she noted that in Japan and Korea, nuclear projects have consistently been completed on time and under budget.

With respect to CWIP, Representative Moses commented that the mechanism does not recognize the "discount rate," or the value that consumers place on having their money in hand throughout the construction process versus ten years later when construction is complete.

<u>Ellen Ruff</u>:

Finally, Representative Moses invited comments from Ellen Ruff, the President of the Office of Nuclear Development for Duke Energy.[18] Ms. Ruff reported that as the third largest electric power holding company in the United States, Duke has electric service territory in five states: North Carolina, South Carolina, Kentucky, Ohio, and Indiana. In Indiana, DEI has 780,000 electric customers and owns 7,000 MW of regulated generating capacity. According to Ms. Ruff, because the average age of DEI's coal-fired assets is 37 years, DEI must consider nuclear power when it plans for replacing its aging generating fleet.

Ms. Ruff then set forth several advantages of nuclear power:

- The addition of 2,000 MW of nuclear capacity can reduce CO_2 emissions by 13 million tons per year. With the addition of this capacity, CO_2 emissions cost savings could reach $1 billion per year by 2030.

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[18]See Exhibit 10.

- A new nuclear plant could create 1,400-1,800 jobs during construction and 400-700 permanent jobs during operation.

- While renewable energy resources offer essentially CO_2-free output, most of those sources are variable and do not provide reliable baseload generation. Nuclear energy offers CO_2-free output and can satisfy the nation's baseload needs at the scale necessary to achieve reductions in greenhouse gas emissions.

Next, Ms. Ruff discussed the importance of favorable credit ratings for utilities seeking financing to develop nuclear projects. Noting that credit rating agencies consider cash flow in assessing a utility's strength, Ms. Ruff claimed that the following regulatory mechanisms are viewed favorably by the agencies:

- Pre-approval by state regulators of construction costs and schedule.
- Periodic reviews of construction costs and schedule compliance.
- Timely recovery of financing costs outside a general rate case.
- No "looking back" by regulators on approved spending.
- Assurance of recovery of the approved investment if the utility is forced to abandon the project.
- Inclusion of the cost of the completed plant in rates without a general rate case.

Ms. Ruff described legislation that was passed in 2007 in North Carolina and South Carolina to enact many of these regulatory mechanisms. She noted that legislation is still needed in those states to allow for the timely recovery of financing costs outside a general rate case. In North Carolina, legislation is also needed to allow for the inclusion of the cost of the completed plant in rates without a general rate case. Ms. Ruff explained that under Indiana law, before beginning the construction of any new plant, a utility must obtain from the IURC a "certificate of need," indicating that the "public convenience and necessity" requires the construction of the plant.[19] This certificate process provides for the IURC's pre-approval of the plant's construction costs and schedule, as well as periodic reviews of the construction and costs.[20] It also allows for the recovery of construction costs outside a rate case upon plant completion.[21] In addition, if a plant is cancelled as a result of the IURC's modification or revocation of the certificate of need, the costs of construction incurred by the utility may be recovered in the utility's rates and amortized over a period of time.[22] However, Indiana law only allows CWIP for clean coal technology or an air pollution control device on a coal-burning plant.[23]

Having discussed the regulatory mechanisms crucial for a utility's financial strength, Ms. Ruff highlighted the advantages of regional partnerships in the development of new nuclear plants. She explained that such partnerships involve investor-owned utilities, municipally owned utilities, and electric cooperatives in neighboring states jointly

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[19]See IC 8-1-8.5-2.

[20]See IC 8-1-8.5-5(b)(1) and IC 8-1-8.5-6.

[21]See IC 8-1-8.5-6.5.

[22]See IC 8-1-8.5-6.5.

[23]See IC 8-1-2-6.6 and IC 8-1-2-6.8.

developing multiple plants in logical succession, rather than concurrently. According to Ms. Ruff, when each participant owns a stake in multiple projects, there is a more efficient deployment of regional resources and more widespread benefits of cost savings and CO_2 reductions.

Before ending, Ms. Ruff asserted that new nuclear development provides significant benefits to customers by reducing CO_2 emissions, replacing aging plants, and lowering fuel costs and emissions compliance costs.

Representative Moses asked about Duke's credit rating. Ms. Ruff indicated that Duke has an "A" rating. She also stated that a utility's rating is usually downgraded during the construction of a plant, especially when CWIP is not available.

Following Ms. Ruff's presentation, the meeting was adjourned at 4:15 p.m.